DIRECT TESTIMONY OF
KENNETH R. JACKSON
ON BEHALF OF
SOUTH CAROLINA ELECTRIC AND GAS COMPANY
DOCKET NO. 2005-113-G

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. Kenneth R. Jackson, 1426 Main Street, Columbia, South Carolina.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am Director of Rates and Regulatory Affairs at SCANA Services, Inc.

Q. DESCRIBE YOUR EDUCATIONAL BACKGROUND AND BUSINESS EXPERIENCE.

A. I am a graduate of the University of South Carolina ("USC") where I received a Bachelor of Science Degree in Business Administration, majoring in Finance. Since graduating from USC, I have completed numerous graduate level courses in Business and Economics. I joined South Carolina Electric & Gas Company ("Company" or "SCE&G") in September 1978, where I held various positions within the Rate Department over the next eighteen years. In May 1997, I became Team Leader for Industrial Marketing. In October 1997, I was promoted to Manager of Marketing Research and Sales for the Large Customer Group. In July 1999, I was promoted to Assistant Controller for the Fossil and Hydro Strategic Business Unit ("SBU"). In May 2005, I became Director of Rates and

Regulatory Affairs. I also currently serve as the Chairman of the Accounting and Finance section of the Southeastern Electric Exchange.

Q. WILL YOU BRIEFLY SUMMARIZE YOUR DUTIES WITH SCANA SERVICES, INC.?

A. I am responsible for the design and administration of the Company's electric and gas rates and tariffs, including the electric fuel adjustment and gas cost adjustment. In addition, I am responsible for the Company's electric and gas cost of service studies, rate design, and regulatory accounting function.

Q. HAVE YOU PRESENTED TESTIMONY TO THIS COMMISSION BEFORE?

A. I have testified before this Commission in numerous previous proceedings.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to support the Settlement Agreement entered into by the Parties on August 10, 2005 ("Settlement Agreement" or "Settlement") which all parties of record in this docket are requesting that the Commission approve. My testimony is also designed to address six of the seven specific questions pertaining to the Settlement that the Commission raised in its motion of August 23, 2005 requesting additional information from the parties. The seventh question, concerning depreciation rates, is addressed by the testimony of John J. Spanos.

I. *Introduction*

Q. BEFORE ADDRESSING THE COMMISSION'S SPECIFIC QUESTIONS, PLEASE EXPLAIN TO THE COMMISSIONERS WHY THE COMPANY HAS REQUESTED A RATE INCREASE AT THIS TIME.

A. SCE&G has not had a general rate increase for its gas operations since 1989. In the intervening sixteen years, the Company has experienced substantial customer growth, with a corresponding investment in infrastructure to serve those customers. For example, since 1989 the number of customers served on SCE&G's gas distribution system has increased from 203,000 to 282,000. The number of miles of gas distribution mains on SCE&G's gas system has increased from 4,667 miles in 1989 to more than 6,800 miles at the close of the test year. Customer demand on the system has increased from a peak design day demand of 268,872 MCF in 1989 to a peak design day of 349,981 MCF for the winter 2004-2005.

Item	1989	2004/2005	% Increase
Number of Customers	203,000	282,000	**39%**
Miles of Mains	4,667	6,800	**46%**
Customer Demand	268,872	349,981	**30%**

Embedded in these numbers is an interesting fact. While customer numbers have increased by 39% during the period, customer demand has increased by only 30%. The lower increase in customer demand has been greatly influenced over the years by an increase in energy-conscious building codes and increased efficiency standards for home heating and water heaters. As a result, the level of SCE&G's firm demand per customer has dropped. These energy efficiencies are good for the State and Nation, but mean, all other things being equal, that SCE&G has lower sales per customer over which to spread its costs of operations.

Q. HOW HAS SCE&G EXPANDED ITS NATURAL GAS DISTRIBUTION SYSTEM DURING THIS PERIOD?

A. Since the last general rate case, SCE&G has made substantial investments in new infrastructure to support the economic development of South Carolina. This investment has included the construction of a line to bring natural gas service to Lake City to support commercial and industrial growth in that area and lines to bring natural gas service to Daniel Island, Mt. Pleasant and Bluffton (Sun City) to support the rapid residential and commercial growth occurring in these coastal areas.

In addition, SCE&G has continued to invest in new gas infrastructure to serve expanding residential and commercial areas around the other major cities we serve. In the Midlands, SCE&G has made substantial investments to provide natural gas to rapidly developing areas in Northeast Columbia, Dutch Fork and Lexington. Natural gas continues to be a very attractive energy source for new home buyers and SCE&G is continuing to add new, single family gas customers at a rapid rate. For example, in our fastest growing divisions, Charleston and

Columbia, the number of new construction, single family gas meters added by year has increased from 2,801 per year in 1998 to 6,344 per year in 2004.

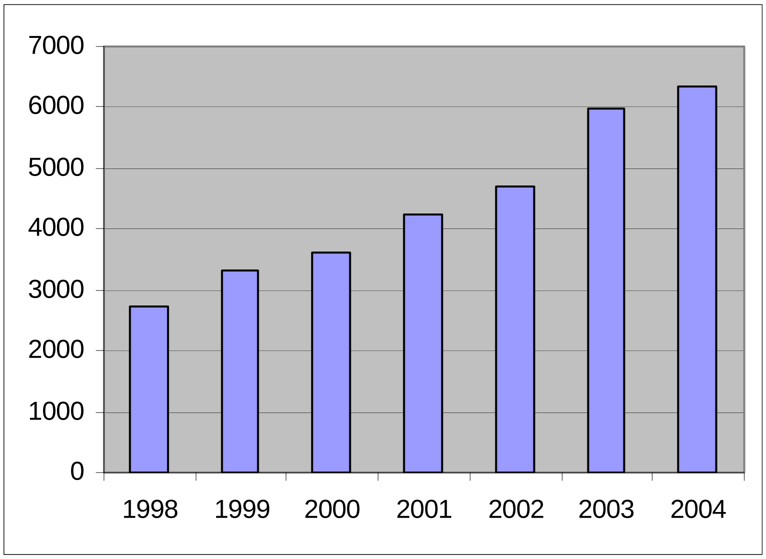

Figure 1: New Construction Single Family Meters Per Year, Charleston and Columbia Divisions

At the same time, SCE&G has continued to expand service in less urban areas. Since 1989, SCE&G has expanded its system to provide service in the towns of Cameron, St. Matthews, Santee, Hardeeville, and Trenton. None of these municipalities had natural gas service in 1989 when our last general rate case was filed.

II. *Commission Questions*

1. *The rate of return of each customer class for the test year and the projected rate of return of each customer class listed in the Settlement Agreement, including information on any supporting data or calculations used in deriving the rates of return by customer class which may be helpful to the Commissioners in evaluating the agreed upon rate design.*

Q. PLEASE EXPLAIN HOW THE COST OF SERVICE AND RATES OF RETURN FOR EACH CUSTOMER CLASS WERE DETERMINED.

A. A Cost of Service Study was performed to determine the cost of serving each customer class and the rate of return on rate base for each class.

Q. WHAT IS A COST OF SERVICE STUDY?

A. A cost of service study measures the Company's costs of serving the various classes of customers (*e.g.*, residential, general service, large general service) and the rates of return on investment provided by them. The Cost of Service Study used in preparing the rates in this proceeding employs principles and methodologies that have been widely accepted in the industry as appropriate for setting rates for natural gas utilities. This Study is based on standard rate making methodologies recognized throughout the industry and the rates based upon it have been agreed to by the parties to this proceeding in the Settlement Agreement.

Q. WHAT ROLE DID THE COST OF SERVICE STUDY PLAY IN TESTING THE PROPOSED RATE DESIGN?

A. The Cost of Service Study was one of the tools that aided and informed us in the rate design. It should be pointed out that cost of service studies for gas rates are intended only to indicate general and relative levels of profitability. Because gas cost of service studies are based upon various assumptions and subjective evaluations, the resulting returns are only indicative and not definitive. Although not definitive, a cost of service study is nevertheless a valuable tool in informing us about the approximate and relative cost of serving each customer class.

Q. WHAT VALUE DID THE COST OF SERVICE STUDY PROVIDE?

A. It validates the rate design and measures the costs associated with providing service to any given customer class. One principle underlying the allocations of plant investment and expenses in a cost of service study is *cost causation*. The allocation methodologies were based on the underlying reasons for the costs' incurrence.

Allocation of the Company's expenses to the category of customers causing funds to be expended is a guiding principle of the rate design. Rates are designed so that differences in rates to consumers reflect the differences in the cost of the elements that go into the final delivery of natural gas service to those customers.

Q. IN RESPONSE TO THE COMMISSION'S FIRST QUESTION IN ITS MOTION OF AUGUST 23, 2005, PLEASE PROVIDE THE RATE OF RETURN OF EACH CUSTOMER CLASS FOR THE TEST YEAR.

A. The rates of return on rate base for each customer class for the test year determined on a regulatory per books basis is as follows: -2.31% for Residential, 10.31% for Small General Service, and 15.90% for Large General Service. This yields a total rate of return of 3.56% during the test year ending December 21, 2004.

Q. PLEASE PROVIDE THE PROJECTED RATES OF RETURN OF EACH CUSTOMER CLASS LISTED IN THE SETTLEMENT AGREEMENT.

A. With the addition of pro forma adjustments to the test year as contained in the Settlement Agreement, the class rates of return are -2.94% for Residential, 8.95% for Small General Service, and 18.62% for Large General Service. This yields an overall rate of return of 3.19%. The effect of the proposed additional revenue reflected in the Settlement results in rates of return of 3.76% for Residential, 21.01% for Small General Service, and 21.31% for Large General Service. This yields an overall rate of return of 8.43%.

Q. PLEASE PROVIDE ANY SUPPORTING DATA OR CALCULATIONS USED IN DERIVING THE RATES OF RETURN BY CUSTOMER CLASS WHICH MAY BE HELPFUL TO THE COMMISSION IN EVALUATING THE AGREED UPON RATE DESIGN.

A. The supporting data and calculations for the projected rates of return based on the Settlement Agreement are provided in the Cost of Service Study attached hereto as Exhibit No. ___ (KRJ-1) and incorporated herein by reference. This Study reflects the cost of service for each customer class taking into account the pro forma adjustments and the proposed revenue requirement agreed to in the Settlement. Additionally, Exhibit No. ___ (KRJ-2), attached hereto, provides a description of the allocators used in performing the cost of service study.

Q. WHAT DID THE COST OF SERVICE STUDY SHOW?

A. The results of the Study showed that the earned rate of return for the test year for the residential class was significantly lower than the Company's overall return, while the returns for all other groups exceeded the overall return for the Company. The Study reinforced the decision to adjust the residential schedules so that the residential class will contribute a positive return and, therefore, provide a more reasonable contribution toward meeting the Company's revenue requirement.

Q. WITH REGARD TO THE RESIDENTIAL CUSTOMER CLASS, DID THE PARTIES SEEK TO FULLY LEVELIZE THE RATE OF RETURN WITH THAT OF OTHER CUSTOMER CLASSES?

A. No. Complete levelization or equalization of rates of return by class would lead to a much larger increase in rates for residential customers. As previously stated, cost of service is only one of several factors considered in designing gas rates. The rates proposed in the Settlement Agreement reflect efforts to design rates using principles of cost causation as a guideline but also utilizing experience and expertise to accomplish the objectives of balancing a reasonable return with reasonable rates for consumers. The rates make progress toward equalization of return for all classes.

Q. WHY IS THE RESIDENTIAL CLASS SEEING A GREATER PERCENTAGE INCREASE IN RATES THAN THE OTHER CLASSES?

A. The progress toward equalization of rates of return means that the residential class will see the greatest percentage increase in natural gas rates among the classes. However, this increase is necessary to bring the residential class from a negative rate of return to a positive one in an effort to ensure that each customer class more fairly bears its cost of service. Customer classes such as the small and large general service classes, who will see a lower overall percentage increase in rates, are currently contributing more toward their cost of service than the residential class.

Additionally, as described above, the small and large general service groups produce a higher rate of return on rate base than the residential class, which is not uncommon in the gas industry.

Q. IS THE RATE DESIGN AN INTEGRAL AND VITAL PART OF THE SETTLEMENT AGREEMENT?

A. Yes. Even though complete equalization of rates of return and equalization of the rate increase among customer classes cannot reasonably be achieved, the parties, including advocates representing the interests of residential customers, small businesses, and large energy users, have all agreed to the tariffs and rate schedules included in the Settlement Agreement. In fact, the parties have agreed that the Settlement Agreement is not binding on any party unless approved in its entirety, as it reflects a careful balancing of many interests.

2. *A more detailed explanation of the new Residential Value Service Rate including the number or percent of customers who would have qualified for the program during the test year and the number of percent of customers projected to qualify for this program, with a particular focus on whether the projections consider the potential impacts of higher rates on consumption.*

Q. PLEASE PROVIDE A DETAILED EXPLANATION OF THE NEW RESIDENTIAL VALUE SERVICE RATE.

A. The Settlement includes two new rates to improve system load factor by providing rate incentives for customers to install non-weather sensitive gas appliances (gas water heaters, dryers and ranges, for example) and to reflect the additional contribution to system revenue made by existing customers with higher summer usage. The new rates are Residential Value Service and Medium General Service. They will apply to customers that meet minimum average load requirements during the summer months.

The Residential Value Service rate, Rate 32V, will apply to customers who average at least 10 therms of gas usage during the months of June, July, and August. Customers qualifying for the Residential Value Service rate will be offered that rate based on a load analysis that the Company will perform annually.

There are several reasons to implement the new Residential Value rate. The new rate provides customers with an economic incentive to improve their summer load, thus utilizing infrastructure and resources in a more efficient manner, which benefits all customers. Increased summer usage allows the

Company to spread its fixed costs of the system, such as the physical infrastructure (including pipes and meters), meter reading, and maintaining customer service, over a greater number of therms, thereby decreasing the charge per therm.

The Residential Value rate is designed to encourage existing heat-only customers and builders to add non-weather sensitive gas appliances in their homes, which benefits the system by improving overall load factor. The Residential Value rate also rewards existing customers who have higher summer usage because of non-weather sensitive appliances. Additionally, the analysis shows that Rate 32V Residential Value Service customers would contribute approximately 15.67% more margin than Rate 32S Residential Standard Service customers due in large part to their improved load factor.

Q. WHAT IS THE SIGNIFICANCE OF THE BREAKPOINT OF 10 THERMS TO QUALIFY FOR THE RESIDENTIAL VALUE RATE?

A. Ten therms is generally the point where the residential load pattern shows a demarcation among seasonal and non-seasonal users. This reflects the amount of therms typically consumed during warmer months when a residential customer has a non-weather sensitive gas appliance such as a water heater, or a combination of a gas range and gas dryer, for example.

The natural gas marketing and operations staff studied different levels of average summer usage to determine the appropriate breakpoint during the summer for customers to be included in the residential value rate. Our analysis showed that starter homes with small families and single residence homes may use as little as 10 therms during the summer with non-weather sensitive applications such as water heating, clothes drying, or cooking. The breakpoint of 10 therms was chosen to include smaller homes and single residence homes with non-weather sensitive applications, and recognize their better load factor and greater contribution to margin revenues.

Q. WHAT ARE THE DIFFERENCES BETWEEN THE RESIDENTIAL VALUE AND THE RESIDENTIAL STANDARD RATES?

The first difference between the Residential Value and Residential Standard rates is in the commodity charge. The commodity charge for the Residential Value rate is six cents less per therm than that of the Residential Standard rate due to the better year-round utilization of gas facilities by the Residential Value customers.

Another difference between the Value and Standard residential rates is the application of the Basic Facilities Charge ("BFC"). Per the Settlement Agreement, for Residential Standard customers, the proposed BFC is $8.38 per month from November through April and $4.91 per month from May through October, which results in a mean annual BFC of $6.64 per month. For Residential Value customers, the BFC is $6.64 per month year round.

Q. WHAT PERCENT OF CUSTOMERS WOULD HAVE QUALIFIED FOR THE PROGRAM DURING THE TEST YEAR?

A. If the Residential Value Service rate had been in effect during the test year, approximately 38% of residential customers would have qualified for the Value rate and approximately 62% of residential customers would have been on the Standard rate.

Q. WHAT PERCENT OF CUSTOMERS ARE PROJECTED TO QUALIFY FOR THE RESIDENTIAL VALUE SERVICE RATE?

A. While the Company cannot make a quantitative projection, it expects that over time the number of customers on the Residential Value Service rate (Rate 32V) will increase.

Q. DO YOUR PROJECTIONS TAKE INTO ACCOUNT THE POTENTIAL IMPACTS OF HIGHER RATES ON CONSUMPTION?

A. We do not expect the increases in rates that result from this proceeding to have a distinct impact on consumption. In fact, customer growth statistics show that dramatic increases in the cost of gas itself over the last several years have not markedly affected consumption. The only factor that we have seen in recent years which has resulted in a noticeable reduction of consumption rates is the increased efficiency of gas appliances. Therefore, we would not expect an increase in rates to reduce consumption such that customers would fail to qualify for the Value Rate simply due to conservation.

3. *Provide information regarding the market factors that led to the creation of new Rate 33 and how the rate was derived.*

Q. PLEASE PROVIDE INFORMATION REGARDING THE NEW RATE 33.

A. The second new rate is Rate 33, Medium General Service. This rate will apply to commercial customers averaging at least 130 therms during the summer months of June, July, and August. Again, the reason for the development of this new rate is to provide an economic incentive to improve their summer usage on the system and recognize the value of existing customers' use of non-seasonal gas appliances that increase summer load. Approximately 20% of current General Service customers fall into a usage pattern of greater than 130 therms. These customers generate approximately 70% of sales in that rate category.

Q. WHAT ARE THE DIFFERENCES BETWEEN THE MEDIUM GENERAL SERVICE RATE AND THE GENERAL SERVICE RATE?

A. The volumetric charge is five cents less per therm for the Medium General Service customer than for the General Service customer, again reflecting the value of their higher summer usage. Additionally, per the Settlement Agreement, the BFC for General Service is $13.36 per month from November through April and $9.19 per month from May through October, which results in a mean annual BFC of $11.28 per month. The BFC for Medium General Service is $19.95 per month. The Medium General Service customers will pay a higher BFC because they typically have larger infrastructure requirements.

Q. PLEASE DISCUSS THE MARKET FACTORS THAT LED TO THE CREATION OF NEW RATE 33 AND HOW THE RATE WAS DERIVED.

A. When the Company analyzed its existing rates, we identified a need for a third commercial rate, one for customers with consumption patterns between small and large commercial users. The group of customers who will qualify for the new Rate 33 has a distinct usage pattern from the other commercial customers. This group has an average summer base use of 739 therms per month, compared to 19 therms per summer month for Small General Service customers.

The creation of this new rate category, like the Residential Value Service rate, will benefit customers who contribute to the efficiency of the system as a whole, which benefits all customers. The customers who will benefit from the new Rate 33 have a higher summer load, which means they are using the system more efficiently and benefiting all customers because there are more therms being consumed through which the Company may recoup its fixed costs.

4. *A more detailed explanation of the modifications to the ISP-R program, focusing on the rationale for changing the cost of gas component in the ISP-R Program and how this was determined.*

5. *A more detailed explanation of the modifications to the Cost of Gas factor including the two-part Demand and Commodity rate structure and the calculation of monthly over and under collections.*

[These questions are addressed together below.]

Q. WHAT ARE THE PRINCIPAL CHANGES IN THE FORMULA FOR THE COST OF GAS CALCULATION?

Two principal changes in the cost of gas calculation are being proposed:

1. The first change relates to how the fixed upstream costs of delivering gas to SCE&G's system are allocated among customer classes for recovery through the Purchased Gas Adjustment ("PGA") factor. Presently, all firm customer classes pay the same PGA factor, which means they pay the same cost per therm for capacity on upstream pipelines. The cost per therm is the same for all customer classes despite the fact that they place very different peak day demands on the system and so require very different levels of upstream capacity to support their demands. Under the Settlement, upstream capacity costs will be allocated among customer classes based on the peak design day demand each customer class places on the system, which more accurately reflects the demand-related nature of these costs.

2. The second change relates to net revenues (as described below) from interruptible service. Per the Settlement, the Company will directly allocate to firm customers the net revenues derived from its interruptible gas service. In the past, interruptible sales were considered in determining when rate adjustments were required, but there was no mechanism for directly allocating the benefit of interruptible sales to firm customer

classes. Under the Settlement, the Company will pass the net interruptible margins through to firm customers in a transparent way by means of a credit to the cost of gas that will be computed in each PGA proceeding, and will be tracked as part of the monthly calculation of over or under collections.

Q. HOW WILL THE NEW PGA METHODOLOGY ALLOCATE UPSTREAM SUPPLY COSTS AMONG CUSTOMER CLASSES?

A. Under the Settlement, SCE&G will divide the current Purchased Gas Adjustment factor into (1) a commodity component which reflects the cost of gas commodity only (referred to in the tariff as the "Firm Commodity Benchmark"), and (2) a demand component which reflects the fixed charges on upstream pipelines (referred to in the tariff as the "Demand Charges" component). All firm customers would be charged the same Firm Commodity Benchmark. However, the Demand Charges component will be calculated for each customer class based on its contribution to peak design day demand. Added together, these two components – the Firm Commodity Benchmark and the class-specific Demand Charges component – will equal the PGA factor for each customer class.

Q. HOW DOES THIS METHOD COMPARE TO THE CURRENT METHOD OF CALCULATING THE PGA FACTOR?

A. Currently, the Company calculates a single PGA factor for all customer classes. It passes through all gas supply costs, including fixed charges on upstream pipelines, using that single factor. Although there is great simplicity to this approach, it is less than optimal. Under it, fixed upstream capacity charges are assigned for recovery using a purely volumetric allocation.

Q. PLEASE EXPLAIN.

A. Included in the gas supply costs that SCE&G pays each month are the fixed monthly capacity charges and reservation fees that SCE&G pays for transportation service, storage service, LNG service and related services on upstream pipelines ("Capacity Charges"). SCE&G pays these Capacity Charges to ensure that upstream transportation and storage services are available to meet firm customer demands on any day of the year, especially the coldest days when firm demands are greatest. Each firm customer class contributes to the level of Capacity Charges SCE&G incurs based on the peak design day demand that the customer class places on the gas system. In short, Capacity Charges are not *volumetric* based costs, but *demand* based costs. However, in past cost of gas calculations, these demand based costs have been passed through to customers on a purely volumetric basis.

Under the Settlement, commodity and other volumetric costs of gas supply would continue to be passed through equally to all firm customer classes using a single Firm Commodity Benchmark. The Demand Charges component, however, would be computed separately for each customer class to recover Capacity

Charges based on the contribution of that customer class to peak design day demand.

Q. HOW WOULD THE COMPANY TRACK THESE COMPONENTS ON A MONTHLY BASIS?

A. SCE&G would track these components very much the same way it tracks the monthly over and under collections under the single-factor PGA presently in use. Currently, after the close of each month, the Company compares the actual commodity costs for the month, and the actual costs incurred for upstream assets, to the actual amounts recovered during that month through the PGA factor. Any over or under collection is calculated and carried forward for crediting or recovery in the next PGA proceeding.

Under the Settlement, monthly over and under balances would continue to be calculated. However, the calculation would be done separately for the Firm Commodity Benchmark and for the Demand Charges component. Because each customer class would bear a different allocation of upstream capacity costs, and each class would provide a different level of recovery of capacity costs based on its individual Demand Charges factor, over and under collections of the Demand Charges would be computed for each customer class separately. These monthly over and under calculations would generate class-specific over or under balances for each customer class. Each customer class would carry forward its own net balance of over and under collections into the next PGA proceeding.

ORS will monitor and verify these calculations on a monthly basis, and audit them annually.

Q. FROM A REGULATORY POLICY STANDPOINT, WHAT ARE THE REASONS FOR USING THIS TWO PART CALCULATION?

A. As mentioned above, the two part calculation results in a better matching of cost recovery with cost causation. These Capacity Costs are demand-based costs and the new mechanism allows for a demand-based recovery of them, and, in addition, more equitable crediting of net interruptible revenues to customer classes. This feature of the mechanism supports the second significant change in the PGA mechanism, *i.e.*, the crediting of net interruptible margins back to firm customers.

Q. PLEASE EXPLAIN.

A. In the Settlement, the parties have agreed to credit the net revenues earned from interruptible or ISP-R service to the firm customers through the cost of gas calculation. This credit will be calculated using the same peak design day demand factor used to allocate Capacity Charges among customer classes. As a result, the PGA will credit net interruptible revenues to each customer class on the same basis on which each class is allocated payment responsibility for the capacity used to serve interruptible customers.

Q. PLEASE EXPLAIN THE INTERRUPTIBLE MARGIN REVENUE CREDIT.

A. Under the Settlement, SCE&G will credit directly to firm customers the net revenue it earns from interruptible sales. Specifically, the calculation of the Demand Charges component for each customer class will include a credit equal to an appropriate allocation of the net revenue that SCE&G derives from interruptible sales.

Q. HOW WOULD SCE&G COMPUTE THE NET INTERRUPTIBLE REVENUE CREDITS FOR THE FIRM COST OF GAS CALCULATION?

A. The net interruptible revenue credit will equal the revenue generated from interruptible sales a) less the average commodity cost of gas for that month, and b) less $0.02081/therm which reflects SCE&G's direct cost of providing service to interruptible customers.

Actual interruptible revenue credits generated would be considered as part of the over and under collection calculations each month. Net over and under collections would be used in setting the PGA for the ensuing period. ORS will monitor and verify these calculations on a monthly basis, and audit them annually.

Q. WHAT IS THE DERIVATION OF THE $0.02081 PER THERM CONTRIBUTION TO SCE&G'S REGULATED COSTS?

A. The $0.02081 figure represents the cost of service for the interruptible customer class for the test period computed on a per therm basis. The $0.02081/therm figure includes both the O&M costs directly associated with serving the interruptible class, as well as costs related to the fixed assets directly allocable to the interruptible class.

Specifically, the $0.02081 factor includes costs associated with the meters and regulating stations located at interruptible customers' plants; costs associated with specific lines serving only those plants; and costs associated with meter reading, billing, customer service, and other direct O&M expenses of serving interruptible customers. In other words, the $0.02081 factor reflects only the costs and investments related specifically to serving interruptible customers.

The $0.02081 does not include the costs associated with assets used to serve firm customers, including the cost of the integrated gas distribution system used by all customers and the upstream capacity assets that are used to serve interruptible loads. Instead, the net margins earned on interruptible service (as passed through the PGA) will be the payment firm customers receive from the interruptible customers for their use of the integrated distribution system and other assets.

Q. WHAT ARE THE REASONS SUPPORTING THE CREDITING OF INTERRUPTIBLE MARGINS TO FIRM CUSTOMERS?

A. There are several reasons to adopt this approach. First, this new approach creates a direct and transparent mechanism for crediting interruptible sales margins to firm customers. Firm customers pay the fixed costs associated with the integrated gas distribution system and the upstream capacity assets used to provide interruptible service. The new mechanism will give firm customers the full benefit of the net revenue created from the use of those assets to serve interruptible customers. It will do so in a way that is direct and transparent.

Additionally, the new method will work well in conjunction with the newly adopted Natural Gas Rate Stabilization Act, S.C. Code §§ 58-5-400, *et seq.* (2005) ("RSA" or "Act"). That Act provides for an annual review of actual gas utility earnings with adjustments in rates up or down if the resulting return on equity falls outside a band of 50 basis points (0.50 percentage points) below or 50 basis points (0.50 percentage points) above the cost of equity on which rates have been set. The existing approach to interruptible sales creates the risk of a wide range of reported earnings under the Act from year to year due to changes in interruptible margin revenue. This could in turn result in an erratic pattern of rate changes under the Act if this new approach is not adopted.

This new mechanism will fairly reflect cost causation in allocating both the expense of upstream capacity and the value of interruptible sales. It will create a direct, fair and easy-to-understand link between interruptible sales and the benefits they provide firm customers. The new mechanism will function well under the RSA recently adopted by our legislature.

Q. HOW WILL THIS NEW PGA METHODOLOGY CHANGE SCE&G'S ISP-R PROGRAM?

A. The new methodology will not substantially change the pricing methodology under the ISP-R program. In fact, alternative fuel customers will not see any change in the program. The only changes will be in how costs and margins are accounted for after sales are made.

Under the ISP-R program, SCE&G would continue to bid competitive gas prices to its customers who have alternative fuel sources. Those bids would be based on the as-fired price of the customer's alternative fuel. SCE&G would continue to be able to make competitively priced bids so long as the gas supplies available at the time would support the sales and would generate a reasonable margin.

As the Commission has long recognized, unless SCE&G has the flexibility to bid effectively against competitive fuels, interruptible customers will be lost to the system and all parties will lose the benefits of the margins those customers could have produced. The new cost of gas methodology creates a more direct alignment between the financial interests of our firm customers and the competitive pricing flexibility that the ISP-R provides. All parties benefit if this important part of SCE&G's competitive structure is maintained, as the Settlement envisions that it will.

Q. WHAT COST OF GAS WILL APPLY TO COMPETITIVELY-PRICED INTERRUPTIBLE SALES?

A. The system-wide commodity cost for each month will apply to competitively-priced interruptible sales. Under the Settlement, SCE&G will no longer allocate specific gas supplies to specific ISP-R customers. SCE&G does not believe that this change will create any significant limitation in its ability to market gas competitively to interruptible customers at this time.

Q. WHAT IS THE PRACTICAL EFFECT OF THIS NEW PGA APPROACH?

A. The practical effect of the new PGA mechanism can be illustrated by applying it using the current PGA factor. This is an illustration only and actual costs will depend on the outcome of future PGA proceedings.

Applying this new cost of gas allocation to the current PGA factor, the firm cost of gas factor drops from $0.90347/therm for all firm customer classes under the current PGA methodology to:

- $0.87609/therm for the Residential class,
- $0.81080/therm for the Commercial class, and
- $0.79425/therm for firm industrial sales customers.

These figures reflect a credit of $10.7 million derived from the net interruptible credits that would have been generated in the test year.

Q. USING THE SETTLEMENT METHODOLOGY, WHAT PORTION OF THESE CHARGES WOULD HAVE CONSTITUTED THE DEMAND CHARGES COMPONENT?

A. Allocating Demand Charges between customer classes based on peak design day percentages, crediting net interruptible revenues to those classes on the same basis, and dividing the result by actual test year sales by class, produces a Demand Charge factor of $0.17807/therm for the Residential class, $0.11278/therm for the Commercial class, and $.09623/therm for firm industrial sales customers under the most recent PGA.

Q. PLEASE EXPLAIN WHAT FIRM COMMODITY BENCHMARK WOULD HAVE APPLIED.

A. The Firm Commodity Benchmark would have been $0.69802/therm, reflecting commodity costs of $281.2 million, less commodity costs of $130.7 million related to interruptible sales, divided by firm sales of 215,660,338 therms. With respect to firm customers, when the class specific demand charge component is added to the system-wide firm commodity benchmark of $0.69802/therm, the result is the firm cost of gas factor for each firm customer class as indicated above.

6. *Information on the physical work that remains for Environmental Clean-Up, with a focus on an explanation as to how the Company will ensure that consumers do not pay twice for Environmental Clean-Up during the transition from collecting these costs in the PGA to collecting them in base rates.*

Q. IN THE SETTLEMENT AGREEMENT, THE PARTIES HAVE AGREED TO A NEW MECHANISM BY WHICH THE COMPANY WOULD RECOVER ENVIRONMENTAL CLEAN UP COSTS. PLEASE DISCUSS THIS NEW MECHANISM.

A. Under the new mechanism, the Company will collect these costs through base rates, recovering some costs as normal operating expenses and using a fixed amortization amount for deferred costs.

Q. PLEASE EXPLAIN.

A. The Environmental Clean Up Cost ("ECC") factor approved in Order No. 94-1117 allows the Company to recover costs related to environmental investigation and remediation at its former manufactured gas plant ("MGP") sites. These are sites where gas was manufactured from coal. The ECC is a volumetric charge on gas sales. The current ECC factor is $0.008 per therm as set in PGA Order No. 2003-652.

The Natural Gas Rate Stabilization Act now allows the Commission to review on an annual basis all costs related to operating SCE&G's natural gas system. Accordingly, the Company proposes to roll the ongoing recovery of MGP costs into base rates. Certain of the ongoing costs, including the cost of routine groundwater monitoring and pumping, would be treated as normal operating costs. In addition, the Company would continue to record appropriate MGP environmental costs in deferred accounts and would amortize deferred costs into expenses using a fixed annual amortization amount. However, collection of the resulting revenue requirements would not be subject to any form of special surcharge.

Q. PLEASE DESCRIBE THE PHYSICAL WORK THAT REMAINS FOR ENVIRONMENTAL CLEAN UP.

A. The clean-up of contaminated sites is conducted under regulatory programs that are administered by either the State (DHEC) or by the federal government (EPA) with the concurrence of the State. In either case, the process moves from an investigative stage, to a remediation implementation stage, to a post-remediation/monitoring stage. This is a simplification as there are many intermediate steps that require negotiation, concurrence, and the approval of the regulators.

All of the estimates that the Company has provided to date are based on reasonable assumptions and past experiences with managing complexities at each site. However, unforeseen challenges and regulator subjectivity are frequently encountered that affect both the schedule and cost. Accordingly, other work may arise. Any expenses associated with that work will be treated in the same manner discussed above.

The remaining work at each of the MGP sites is explained on a site by site basis below.

<u>Charleston MGP</u>, ½ Charlotte Street (near Concord Street)

To date, over 63,000 tons of impacted material have been removed from the site and disposed of. Over three million gallons of water have been pumped, treated, and released to the sanitary sewer system. A tar recovery system has removed over 16,000 gallons of tar from areas not accessible for excavation.

Besides continued pumping of tar, remaining work must address additional groundwater and sediment issues. For groundwater, SCE&G is currently treating six off-site areas by chemical oxidation technologies. After the first phase of treatment, the sites will be reassessed for possible additional remediation measures. The approach for addressing impacts to sediment at the site consists of capping three areas near the shoreline where the thickness of the existing sand blanket (installed as protective measure during construction of the Aquarium and Tour Boat Facility) may not be sufficient. The implementation schedule is being coordinated with the City of Charleston and other parties to minimize disruption of other activities.

In addition to the ongoing remediation activities, there are more routine operation and maintenance (O&M) activities in place that will continue for many years, including (1) groundwater sampling, reporting, and treatment; (2) the treatment and disposal of tar; and (3) well repair, replacement, and abandonment.

<u>Sumter MGP,</u> 130 Hauser Street (near Brooklyn Street)

To date, a total of 8,130 tons of contaminated soil material has been excavated and disposed of. SCE&G will complete a Remedial Investigation and Feasibility Study (RI/FS), including the evaluation of potential final remedies for the Site. The Company will benefit from the previous removal actions because they will simplify the implementation of any potential final remedies, if necessary, at the site.

Future activities are expected to include routine follow-up monitoring of groundwater to determine if the remediation activities have been sufficiently effective, which may continue for at least the next 3 to 5 years.

<u>Florence MGP,</u> 553 North Irby Street (near Lucas Street, US-52)

SCE&G recently completed the investigation stage and has submitted a Focused Feasibility Study (FFS) to DHEC detailing alternate remediation options with a wide range of costs that may be utilized for site clean-up. Because the selected remedy or combination of alternatives will ultimately be selected and required by DHEC, the final costs are difficult to estimate at this time. However, the Company has utilized cost figures for what it believes to be a reasonable remedy. There are no current expenses which are categorized as routine O&M activities.

<u>Columbia MGP,</u> 1409 Huger Street (near Washington Street)

The site was formerly operated as a bus fleet maintenance facility and is currently leased by the City of Columbia for the Regional Transit Authority (RTA). The City and RTA must vacate the property by October 2007 and allow SCE&G three years to conduct cleanup activities, and in 2010 the property will be transferred to the City of Columbia.

Investigation and assessment work to date has shown only minor impacts and no offsite migration of contaminated groundwater. We are currently working with DHEC to have an approved remediation plan in place prior to the property being vacated in 2007. Delays to the site clean-up due to limited site access have made a final estimate of total cost imprecise.

Pursuant to an agreement with DHEC, SCE&G also cleaned up the site by removing and disposing of 3,900 tons of contaminated soil. Routine follow-up work at the site consists of semi-annual groundwater sampling, analysis and reporting.

<u>Macon Dockery,</u> State Road 1103, 1.6 miles southwest of Cordova, NC

(16 acre farmland)

EPA-required remediation activity has been implemented and some of the systems have been dismantled. Operation of the pump and treat system and quarterly reporting are ongoing and are considered to be routine O&M activities.

Q. PLEASE EXPLAIN HOW THE COMPANY WILL ENSURE THAT CONSUMERS DO NOT PAY TWICE FOR ENVIRONMENTAL CLEANUP DURING THE TRANSITION FROM COLLECTING THOSE COSTS IN THE PGA TO COLLECTING THEM IN BASE RATES.

A. The transition from the collection of environmental cleanup costs through the existing ECC factor to collecting them in base rates will take place simultaneously with the first billing cycle of November 2005. All collections through the ECC factor up to that point will be credited toward the recovery of ECC expenses before the costs associated with environmental cleanup begin to be collected through base rates. Therefore, customers will not be billed twice for the same environmental cleanup costs.

III. *Conclusion*

Q. WHAT ACTION ARE THE PARTIES REQUESTING THAT THE COMMISSION TAKE IN THIS PROCEEDING?

A. The Settlement Agreement provides:

> The Parties agree to advocate that the Commission accept and approve this Settlement Agreement in its entirety as a fair, reasonable and full resolution of the above-captioned proceeding and to take no action inconsistent with its adoption by the Commission. The Parties further agree to cooperate in good faith with one another in recommending to the Commission that this Settlement Agreement be accepted and approved by the Commission. The Parties agree to use reasonable efforts to defend and support any Commission order issued approving this Settlement Agreement and the terms and conditions contained herein. . . . If the Commission should decline to approve the agreement in its entirety, then any Party desiring to do

so may withdraw from the Settlement Agreement without penalty or obligation.

Consistent with the Settlement Agreement, the parties therefore jointly request that the Commission approve the Settlement Agreement in its entirety, without change or modification, and issue an order incorporating the Settlement Agreement by reference and approving the rates and charges set forth in Exhibit D to the Settlement Agreement for service on and after the first billing cycle of November 2005.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

	Description	TOTAL	RESIDENTIAL	SMALL	LARGE	FIRM	INTERRUPTIBLE
1	**TOTAL REVENUES**	424,308,371	175,942,832	108,201,703	10,632,401	294,776,936	129,531,435
2	**OPERATING EXPENSES**						
3	O&M EXPENSES - FUEL	314,983,882	110,865,215	73,211,649	5,268,041	189,344,905	125,638,977
4	- OTHER	48,367,903	35,283,886	9,872,066	1,352,794	46,508,746	1,859,156
5	DEPRECIATION & AMORIZATION EXPENSE	15,800,604	11,380,364	3,631,075	569,355	15,580,794	219,810
6	TAXES OTHER THAN INCOME	13,315,923	9,232,391	3,186,761	468,211	12,887,363	428,560
7	TOTAL INCOME TAXES	9,074,630	1,771,924	5,402,828	827,325	8,002,076	1,072,554
8	**TOTAL OPERATING EXPENSES**	401,542,942	168,533,781	95,304,379	8,485,726	272,323,885	129,219,057
9	**OPERATING RETURN**	22,765,429	7,409,052	12,897,324	2,146,675	22,453,051	312,378
10	**INTEREST ON CUSTOMER DEPOSITS**	(165,780)	(123,419)	(42,361)	-	(165,780)	-
11	**RETURN**	22,599,649	7,285,632	12,854,963	2,146,675	22,287,271	312,378
12	**RATE BASE**						
13	GAS PLANT IN SERVICE	528,352,568	378,262,899	123,251,820	19,688,248	521,202,967	7,149,600
14	RESERVE FOR DEPRECIATION	(215,459,446)	(153,701,259)	(50,679,652)	(8,141,771)	(212,522,682)	(2,936,765)
15	NET PLANT	312,893,121	224,561,640	72,572,168	11,546,478	308,680,286	4,212,836
16	TOTAL CONSTRUCTION WORK IN PROGRESS	4,121,639	2,922,849	982,021	158,630	4,063,500	58,139
17	DEFERRED DEBITS/CREDITS	(6,917,910)	(4,671,317)	(1,811,103)	(169,063)	(6,651,483)	(266,427)
18	TOTAL WORKING CAPITAL	(5,791,618)	(3,334,881)	(1,846,969)	(71,896)	(5,253,746)	(537,872)
19	TOTAL MATERIALS & SUPPLIES	1,463,812	1,073,693	330,473	59,377	1,463,542	270
20	ACCUMULATED DEFERRED INCOME TAXES	(37,771,135)	(26,719,697)	(9,031,638)	(1,448,172)	(37,199,507)	(571,628)
21	**TOTAL RATEBASE**	267,997,909	193,832,286	61,194,953	10,075,354	265,102,592	2,895,317
22	**RATE OF RETURN**	8.43%	3.76%	21.01%	21.31%	8.41%	10.79%

	Description	Allocator	TOTAL	RESIDENTIAL	SMALL	LARGE	FIRM	INTERRUPTIBLE
	Gas Plant in Service							
1	LAND & LAND RIGHTS	MDEM1	42,619	31,238	9,655	1,726	42,619	-
2	PROD STRUCTURES & IMP	MDEM1	2,047,047	1,500,427	463,722	82,898	2,047,047	-
3	LP GAS EQUIPMENT	MDEM1	8,682,356	6,363,917	1,966,834	351,605	8,682,356	-
4	PROD OTHER	MDEM1	455,151	333,613	103,106	18,432	455,151	-
5	**TOTAL PRODUCTION**		11,227,173	8,229,195	2,543,317	454,661	11,227,173	-
6	DIST LAND & LAND RIGHTS	RB_A_PLT_DI_O_	605,862	429,458	144,445	23,302	597,205	8,657
7	DIST STRUCTURES & IMPROVEMENTS	MDEM4	618,062	321,368	127,702	29,524	478,594	139,467
8	DIST MAINS	MDEM3	216,840,067	140,120,365	61,452,713	15,266,989	216,840,067	-
9	DIST MEAS & REG STA EQUIP-GEN	MDEM4	3,570,274	1,856,404	737,681	170,546	2,764,632	805,643
10	DIST SERVICES	MCW1	175,323,317	148,889,802	24,943,140	946,911	174,779,853	543,464
11	DIST METERS	MCW2	53,713,996	31,482,894	20,988,512	384,861	52,856,267	857,729
12	DIST IND REG STA	MDEM4	4,917,803	2,557,067	1,016,104	234,916	3,808,087	1,109,717
13	DIST IND REG STA - Directly Assigned	MC385DA	3,833,395	-	121,147	612,940	734,086	3,099,309
14	DIST OTHER EQUIPMENT	RB_A_PLT_DI_O_	116,808	82,798	27,849	4,493	115,139	1,669
15	**TOTAL DISTRIBUTION**		459,539,585	325,740,155	109,559,293	17,674,482	452,973,930	6,565,655
16	COM MISC INTANGIBLE PLT	MCUSTY	17,321,463	15,732,274	1,559,733	8,776	17,300,782	20,681
17	GEN LAND & LAND RIGHTS	WORKPD	1,286,033	912,240	306,286	49,517	1,268,043	17,991
18	COM LAND & LAND RIGHTS	WORKPD	959,318	680,487	228,474	36,937	945,898	13,420
19	GEN OTHER GENERAL PLANT	WORKPD	30,600,433	21,706,236	7,287,891	1,178,232	30,172,358	428,074
20	COM OTHER GENERAL PLANT	WORKPD	7,418,562	5,262,313	1,766,827	285,643	7,314,782	103,779
21	**TOTAL GENERAL AND COMMON**		57,585,809	44,293,549	11,149,210	1,559,105	57,001,864	583,945
22	**TOTAL GAS PLANT**		528,352,568	378,262,899	123,251,820	19,688,248	521,202,967	7,149,600

	Description	Allocator	TOTAL	RESIDENTIAL	SMALL	LARGE	FIRM	INTERRUPTIBLE
	Accumulated Reserves for Depreciation							
1	RES PROD PLANT	RB_A_PLT_PR_O	(5,759,732)	(4,221,718)	(1,304,765)	(233,249)	(5,759,732)	-
2	RES DIST PLT	RB_A_PLT_DI_O	(187,597,140)	(132,975,763)	(44,725,538)	(7,215,173)	(184,916,473)	(2,680,667)
3	RES GEN & COM PLT	WORKPD	(17,952,696)	(12,734,639)	(4,275,668)	(691,247)	(17,701,553)	(251,143)
4	RES INTANGIBLE PLANT	MCUSTY	(4,149,878)	(3,769,140)	(373,681)	(2,102)	(4,144,923)	(4,955)
5	**TOTAL RESERVES**		(215,459,446)	(153,701,259)	(50,679,652)	(8,141,771)	(212,522,682)	(2,936,765)
6	**NET GAS PLANT IN SERVICE**		312,893,121	224,561,640	72,572,168	11,546,478	308,680,286	4,212,836
	Construction Work in Progress							
7	DIST PLT CWIP	RB_A_PLT_DI_O	1,599,227	1,133,591	381,276	61,508	1,576,375	22,852
8	GEN & COM CWIP	WORKPD	2,522,412	1,789,258	600,745	97,122	2,487,126	35,286
9	**TOTAL CWIP**		4,121,639	2,922,849	982,021	158,630	4,063,500	58,139

	Description	Allocator	TOTAL	RESIDENTIAL	SMALL	LARGE	FIRM	INTERRUPTIBLE
	OTHER RATE BASE ITEMS							
1	**REGULATORY ASSETS - ECC**	MDEM1	1,701,912	1,247,453	385,538	68,921	1,701,912	-
2	**OTHER DEFERRED CREDITS - OPEBS**	LAB_A_	(8,619,822)	(5,918,770)	(2,196,641)	(237,985)	(8,353,395)	(266,427)
3	**INJURIES AND DAMAGES**	RB_A_PLT	(226,782)	(162,877)	(52,514)	(8,348)	(223,739)	(3,043)
	Materials and Supplies							
4	PROPANE INVENTORY	MDEM1	1,173,624	860,233	265,864	47,528	1,173,624	-
5	M&S PIPE	RB_A_PLT_DI_O__ALOC	244,661	180,713	53,638	10,157	244,508	153
6	COMMON M&S	WORK155	45,527	32,748	10,970	1,692	45,410	117
7	**TOTAL MATERIAL AND SUPPLIES**		1,463,812	1,073,693	330,473	59,377	1,463,542	270
8	**WORKING CASH**		6,045,988	4,410,486	1,234,008	169,099	5,813,593	232,395
	Prepayments							
9	PREPAID OTHER	WORKPD	384,806	272,960	91,647	14,816	379,423	5,383
10	PREPAID INSURANCE	WORKPD	295,283	209,457	70,325	11,370	291,152	4,131
11	PREPAID MUNI LICENSES	MFFEE	(962,612)	(509,833)	(313,686)	(13,607)	(837,126)	(125,486)
12	**TOTAL PREPAYMENTS**		(282,523)	(27,416)	(151,714)	12,579	(166,551)	(115,972)
13	**AVG TAX ACCRUALS**		(5,926,894)	(3,533,863)	(1,496,554)	(245,226)	(5,275,642)	(651,252)
14	**CUST DEPOSITS**	MCDEPS	(5,401,407)	(4,021,211)	(1,380,196)	-	(5,401,407)	-
	ACCUMULATED DEFERRED INCOME TAXES							
15	ACCUM DEF INC TAXES - PROD	RB_A_PLT_PR_O	2,206,117	1,617,020	499,757	89,340	2,206,117	-
16	ACCUM DEF INC TAX - DIST	RB_A_PLT_DI_O	(41,221,564)	(29,219,363)	(9,827,744)	(1,585,422)	(40,632,529)	(589,035)
17	ACCUM DEF INC TAX - GEN & COM	WORKPD	(7,045,188)	(4,997,462)	(1,677,903)	(271,266)	(6,946,632)	(98,556)
18	ACCUM DEF INC TAX - OTHER	WORKPD	8,289,500	5,880,108	1,974,252	319,177	8,173,537	115,963
19	**TOTAL ACCUMULATED DEFERRED INCOME TAXES**		(37,771,135)	(26,719,697)	(9,031,638)	(1,448,172)	(37,199,507)	(571,628)
20	**TOTAL RATE BASE**		267,997,909	193,832,286	61,194,953	10,075,354	265,102,592	2,895,317

	Description	Allocator	TOTAL	RESIDENTIAL	SMALL	LARGE	FIRM	INTERRUPTIBLE
	REVENUE							
1	**RATE SCHEDULE REVENUE**	MRSL	419,624,658	174,891,239	107,809,930	7,837,129	290,538,298	129,086,360
2	Delinquent Charges	MCX904	599,074	424,759	81,055	22,470	528,285	70,789
3	MISC SERVICE REVENUE	MWRSL	582,137	358,676	223,461	-	582,137	-
4	Transportation Revenue	MTRSL	3,128,101	-	-	2,758,870	2,758,870	369,231
5	RENT FROM GAS PROPERTY	RB_A_PLT_??_O	46,344	33,193	10,801	1,725	45,718	626
6	OTHER GAS REVENUES	RB_A_PLT_??_O	328,057	234,965	76,455	12,207	323,628	4,429
7	**TOTAL OTHER REVENUE**		4,683,713	1,051,593	391,773	2,795,272	4,238,638	445,075
8	**TOTAL REVENUE**		424,308,371	175,942,832	108,201,703	10,632,401	294,776,936	129,531,435

	Description	Allocator	TOTAL	RESIDENTIAL	SMALL	LARGE	FIRM	INTERRUPTIBLE
	OPERATIONS AND MAINTENANCE EXPENSE							
	Production Expense							
1	Oper Supervision and Engr M	MDEM1	31,573	23,142	7,152	1,279	31,573	-
2	Oper Liq Petroleum Gas Exp	MDEM1	18,178	13,324	4,118	736	18,178	-
3	Environ Amort and Misc Oper	MDEM1	2,570,294	1,883,951	582,254	104,088	2,570,294	-
4	Maint Struct and Impr MGP	MDEM1	90	66	20	4	90	-
5	Maint Production Equip MGP	MDEM1	2,062	1,511	467	83	2,062	-
6	**TOTAL PRODUCTION EXPENSE**		2,622,196	1,921,994	594,012	106,190	2,622,196	-
7	**COST OF GAS**	METHR	314,983,882	110,865,215	73,211,649	5,268,041	189,344,905	125,638,977
	Distribution Operations							
8	Supervision and Engr NG Dis	WORKPD	807,397	572,722	192,292	31,088	796,102	11,295
9	Load Dispatching NG Dist Op	WORKPD	4,926	3,494	1,173	190	4,857	69
10	Mains and Services Exp NG D	RB_A_PLT_DI_O__ALOC	4,443,921	3,268,091	983,472	183,024	4,434,587	9,334
11	Meas and Reg Station Exp Ge	RB_A_PLT_DI_O__378	811,508	290,677	123,485	67,073	481,235	330,272
12	Meter and House Regulator E	MCW2	2,780,995	1,629,999	1,086,662	19,926	2,736,587	44,408
13	Cust Installation NG Dist O	MCW2	947,016	555,066	370,042	6,785	931,893	15,122
14	Other Expenses NG Dist Oper	RB_A_PLT_DI_O	505,021	357,977	120,403	19,424	497,804	7,216
15	Rents NG Dist Oper	RB_A_PLT_DI_O	355	252	85	14	350	5
16	**TOTAL DISTRIBUTION OPERATIONS EXPENSE**		10,301,136	6,678,277	2,877,614	327,523	9,883,414	417,722
	Distribution Maintenance							
17	Maint Supervision and Engr	LAB_A_O&M_DM_	63,579	45,067	15,158	2,445	62,670	909
18	Maint Structures and Improv	EXP_A_O&M_DM_	13,663	9,346	3,297	612	13,255	408
19	Maint Mains NG Dist	MDEM3	1,769,158	1,143,216	501,381	124,561	1,769,158	-
20	Maint Meas and Reg Station	RB_A_PLT_DI_O__378	112,334	40,237	17,094	9,285	66,615	45,718
21	Maint Meas and Reg Station	RB_A_PLT_DI_O__378	110,163	39,460	16,763	9,105	65,328	44,835
22	Maint Services NG Dist	MCW1	930,318	808,707	119,580	629	928,916	1,402
23	Maint Meters and House Regu	MCW2	337,073	197,566	131,710	2,415	331,691	5,383
24	Maint Other Equipment NG Di	EXP_A_O&M_DM_	6,655	4,552	1,606	298	6,456	199
25	**TOTAL DISTRIBUTION MAINTENANCE EXPENSE**		3,342,942	2,288,150	806,589	149,350	3,244,089	98,853

	Description	Allocator	TOTAL	RESIDENTIAL	SMALL	LARGE	FIRM	INTERRUPTIBLE
	CUSTOMER EXPENSE							
	Customer Accounting							
1	Supervision Cust Acct	EXP_A_O&M_CUST_ACCT_	209,242	187,765	19,359	529	207,653	1,588
2	Meter Reading Expenses Cust	MCUSTY	2,737,863	2,486,672	246,534	1,387	2,734,594	3,269
3	Billing and Accounting Exp	MCUSTY	6,949,695	6,312,083	625,794	3,521	6,941,397	8,298
4	Uncollectible Accounts Cust	MCX904	560,371	397,317	75,819	21,019	494,155	66,216
5	Misc Cust Accounts Exp Cust	EXP_A_O&M_CUST_ACCT_	521,027	321,610	33,159	51,278	406,047	114,980
6	**TOTAL CUSTOMER ACCOUNTING EXPENSE**		10,978,197	9,705,447	1,000,665	77,734	10,783,846	194,351
	Customer Service							
7	Supervision Cust Serv	EXP_A_O&M_CUST_SERV_	657,367	597,055	59,193	333	656,582	785
8	Customer Assistance Exp Cus	MCUSTY	449,888	408,612	40,511	228	449,350	537
9	Info and Instruct Advert Ex	MCUSTY	-	-	-	-	-	-
10	Misc Cust Serv and Informat	EXP_A_O&M_CUST_SERV_	81,327	73,866	7,323	41	81,230	97
11	**TOTAL CUSTOMER SERVICE EXPENSE**		1,188,581	1,079,533	107,027	602	1,187,162	1,419
	Sales							
12	Supervision Sales	EXP_A_O&M_SALES_MISC	537,066	388,303	69,766	23,800	481,870	55,197
13	Demonstrating and Selling E	MCX912	2,747,666	1,973,935	358,193	125,194	2,457,322	290,344
14	Advertising Exp Sales	MCX913	77,792	68,895	8,839	18	77,752	40
15	Misc Sales Exp Sales	MCX916	176,760	130,226	26,269	6,106	162,600	14,160
16	**TOTAL SALES EXPENSE**		3,539,285	2,561,359	463,067	155,119	3,179,544	359,741

	Description	Allocator	TOTAL	RESIDENTIAL	SMALL	LARGE	FIRM	INTERRUPTIBLE
	ADMINISTRATIVE AND GENERAL EXPENSE							
1	A and G Salaries	LAB_A_O&MA&G_920	6,806,401	4,803,058	1,638,697	251,232	6,692,987	113,414
2	A and G Off Supp and Expens	LAB_A_	2,716,617	1,865,355	692,292	75,003	2,632,650	83,967
3	A and G Outside Svcs	LAB_A_O&M_	1,271,543	870,690	325,818	33,969	1,230,477	41,066
4	A and G Property Insurance	RB_A_PLT_??_O	29,050	20,807	6,770	1,081	28,658	392
5	A and G Injuries and Damage	LAB_A_O&M_	557,832	381,976	142,938	14,902	539,816	18,016
6	A and G Pension	LAB_A_	3,408,371	2,340,346	868,576	94,102	3,303,023	105,348
7	A and G Franch Requirements	MFFEE	18	10	6	0	16	2
8	A and G Reg Comm Exps	REV_A_	335,055	130,043	80,798	7,944	218,785	116,270
9	A and G Duplicate Chgs Cr	LAB_A_	(985,552)	(676,725)	(251,154)	(27,210)	(955,090)	(30,462)
10	A and G Gen Advert Exps	MDTHR	661,898	203,168	123,579	36,433	363,179	298,719
11	A and G Rents	LAB_A_O&M_	1,000,967	685,413	256,486	26,741	968,639	32,327
12	A and G Maint General Plant	RB_A_PLT_??_O	593,364	424,987	138,286	22,080	585,353	8,011
13	**TOTAL ADMINISTRATIVE AND GENERAL EXPENSE**		16,395,564	11,049,126	4,023,091	536,277	15,608,494	787,071
14	**TOTAL O&M EXPENSES**		363,351,785	146,149,101	83,083,715	6,620,835	235,853,652	127,498,133

	Description	Allocator	TOTAL	RESIDENTIAL	SMALL	LARGE	FIRM	INTERRUPTIBLE
	DEPRECIATION EXPENSE							
1	DEPREC EXP PROD	RB_A_PLT_PR_R	(401,712)	(294,443)	(91,001)	(16,268)	(401,712)	-
2	DEPREC EXP DIST	RB_A_PLT_DI_R	11,627,043	8,241,676	2,772,035	447,188	11,460,899	166,144
3	DEPREC EXP INTANGIBLE	RB_A_PLT_IN_R	926,033	841,072	83,386	469	924,927	1,106
4	DEPREC EXP GEN & COMMON	WORKPDR	3,112,497	2,208,545	740,930	119,903	3,069,379	43,118
5	DEPREC EXP SCANA SERVICE COMPANY	DEP_A_	536,743	383,513	125,726	18,063	527,302	9,441
6	**TOTAL DEPRECIATION EXPENSE**		15,800,604	11,380,364	3,631,075	569,355	15,580,794	219,810
	TAXES OTHER THAN INCOME							
7	FED PAYROLL TAXES	LAB_A_	1,734,451	1,190,955	442,001	47,886	1,680,842	53,609
8	STATE LICENSE TAX	RB_A_PLT_??_O	291,085	208,485	67,839	10,832	287,155	3,930
9	COUNTY PROPERTY TAXES	RB_A_PLT_??_O	10,298,650	7,376,231	2,400,151	383,227	10,159,609	139,041
10	GROSS RECEIPTS TAX		991,737	456,721	276,771	26,266	759,758	231,979
11	**TOTAL OTHER TAXES**		13,315,923	9,232,391	3,186,761	468,211	12,887,363	428,560

	Description	Allocator	TOTAL	RESIDENTIAL	SMALL	LARGE	FIRM	INTERRUPTIBLE
	DEVELOPMENT OF STATE INCOME TAX LIABILITY							
1	**OPERATING RETURN BEFORE TAXES**	FORMULA	31,840,059	9,180,976	18,300,151	2,974,000	30,455,127	1,384,932
	Allowable Deductions							
2	ADDITIONAL DEPRECIATION	DEP_A	2,803,149	2,029,316	637,085	100,060	2,766,461	36,688
3	INTEREST	WORKBATA	8,196,015	5,902,548	1,878,021	309,002	8,089,572	106,444
4	DEFERRED FUEL	MENE2	(746,928)	(4,329,026)	3,324,990	257,108	(746,928)	-
5	PLANT ALLOCATED ITEMS	RB_A_PLT_??_O	859,555	615,641	200,324	31,985	847,950	11,605
6	EMPLOYEE BENEFITS	LAB_A_	(233,449)	(160,297)	(59,491)	(6,445)	(226,233)	(7,216)
7	**ALLOWABLE STATE DEDUCTIONS**		10,878,342	4,058,182	5,980,929	691,710	10,730,822	147,521
8	**STATE TAXABLE INCOME**	FORMULA	20,961,716	5,122,793	12,319,222	2,282,290	19,724,305	1,237,411
9	STATE INCOME TAX	FORMULA	1,045,172	255,428	614,249	113,797	983,473	61,699
10	STATE PRIOR YR TAX ADJUSTMENTS	RB_A_PLT_??_O	558,600	400,088	130,184	20,786	551,058	7,542
11	**STATE INC TAX LIABILITY**	FORMULA	1,603,772	655,515	744,433	134,584	1,534,532	69,240

	Description	Allocator	TOTAL	RESIDENTIAL	SMALL	LARGE	FIRM	INTERRUPTIBLE
	DEVELOPMENT OF FEDERAL INCOME TAX LIABILITY							
1	**OPERATING RETURN BEFORE TAXES**	FORMULA	31,840,059	9,180,976	18,300,151	2,974,000	30,455,127	1,384,932
	Allowable Deductions							
2	ADDITIONAL DEPRECIATION	DEP_A	2,719,863	1,969,022	618,157	97,087	2,684,265	35,598
3	INTEREST	WORKBATA	8,196,015	5,902,548	1,878,021	309,002	8,089,572	106,444
4	DEFERRED FUEL	MENE2	(746,928)	(4,329,026)	3,324,990	257,108	(746,928)	-
5	PLANT ALLOCATED ITEMS	RB_A_PLT_??_O	859,555	615,641	200,324	31,985	847,950	11,605
6	EMPLOYEE BENEFITS	LAB_A_	(233,449)	(160,297)	(59,491)	(6,445)	(226,233)	(7,216)
7	STATE TAX CALCULATION	FORMULA	1,045,172	255,428	614,249	113,797	983,473	61,699
8	**ALLOWABLE FEDERAL DEDUCTIONS**		11,840,228	4,253,316	6,576,249	802,534	11,632,099	208,129
9	**FEDERAL TAXABLE INCOME**	FORMULA	19,999,831	4,927,660	11,723,902	2,171,466	18,823,028	1,176,803
10	FEDERAL INCOME TAX	FORMULA	6,981,398	1,720,112	4,092,496	758,000	6,570,608	410,790
11	FED PRIOR YR TAX ADJUSTMENTS	RB_A_PLT_??_O	2,678,200	1,918,215	624,168	99,659	2,642,042	36,158
12	**FEDERAL INCOME TAX LIABILITY**	FORMULA	9,659,598	3,638,327	4,716,664	857,659	9,212,650	446,948

	Description	Allocator	TOTAL	RESIDENTIAL	SMALL	LARGE	FIRM	INTERRUPTIBLE
	DEFERRED INCOME TAXES							
1	DEPRECIATION	DEP_A	3,482,800	2,521,344	791,553	124,320	3,437,217	45,583
2	LABOR AND BENEFITS	LAB_A_	(4,159,000)	(2,855,762)	(1,059,863)	(114,826)	(4,030,451)	(128,549)
3	UNCOLLECTABLES	MCX904	(24,600)	(17,442)	(3,328)	(923)	(21,693)	(2,907)
4	ENVIRONMENTAL	MDEM1	(1,426,900)	(1,045,877)	(323,239)	(57,784)	(1,426,900)	-
5	COST OF GAS	METHRF	(285,700)	(172,071)	(113,629)	-	(285,700)	
6	FRANCHISE FEES	MFFEE	(84,100)	(44,542)	(27,406)	(1,189)	(73,137)	(10,963)
7	REVENUE	MRSL	(705,900)	(729,207)	22,683	29	(706,495)	595
8	PREPAYMENTS	RB_A_OTH_PP	1,625,800	157,768	873,048	(72,385)	958,431	667,369
9	PLANT	RB_A_PLT	(313,440)	(122,907)	(148,708)	(31,082)	(302,697)	(10,743)
10	**TOTAL DEFERRED INCOME TAX (NET)**		(1,891,040)	(2,308,696)	11,111	(153,840)	(2,451,425)	560,385
11	**INVESTMENT TAX CREDIT (NET)**	RB_A_PLT_??_O	(297,700)	(213,223)	(69,380)	(11,078)	(293,681)	(4,019)
12	**INTEREST ON CUSTOMER DEPOSITS**	MCDEPS	(165,780)	(123,419)	(42,361)	-	(165,780)	-
13	**OPERATING RETURN AFTER TAXES**	FORMULA	22,599,649	7,285,632	12,854,963	2,146,675	22,287,271	312,378

SCE&G Cost of Service Allocators - 12 Months Ending December 31, 2004

Allocator	Description	Residential	Small	Large	Firm	Interruptible
DEP_A_	Depreciation Expense	72.39%	22.73%	3.57%	98.69%	1.31%
EXP_A_O&M_CUST_ACCT_	Customer Accounting Expense	89.74%	9.25%	0.25%	99.24%	0.76%
EXP_A_O&M_CUST_SERV_	Customer Service Expense	90.83%	9.00%	0.05%	99.88%	0.12%
EXP_A_O&M_DM_	Accounts 887-893	68.40%	24.13%	4.48%	97.01%	2.99%
EXP_A_O&M_SALES_MISC	Accounts 912-913	72.30%	12.99%	4.43%	89.72%	10.28%
LAB_A_	Total Labor	68.66%	25.48%	2.76%	96.91%	3.09%
LAB_A_O&M_	Labor from O&M Accounts	68.48%	25.62%	2.67%	96.77%	3.23%
LAB_A_O&M_DM_	Labor Accounts 886-894	70.88%	23.84%	3.85%	98.57%	1.43%
LAB_A_O&MA&G_920	Labor Accounts 925, 928-931	70.88%	23.84%	3.85%	98.57%	1.43%
MC385DA	M&R Direct Assignment	0.00%	3.16%	15.99%	19.15%	80.85%
MCDEPS	Customer Deposits	74.45%	25.55%	0.00%	100.00%	0.00%
MCUSTY	Average Annual Customers	90.83%	9.00%	0.05%	99.88%	0.12%
MCW1	Weighted Services Allocator	86.93%	12.85%	0.07%	99.85%	0.15%
MCW2	Weighted Meters Allocator	58.61%	39.07%	0.72%	98.40%	1.60%
MCX904	Uncollectibles	70.90%	13.53%	3.75%	88.18%	11.82%
MCX912	Demonstrating and Selling Expense	71.84%	13.04%	4.56%	89.43%	10.57%
MCX913	Advertising Expense	88.56%	11.36%	0.02%	99.95%	0.05%
MCX916	Miscellaneous Sales Expense	73.67%	14.86%	3.45%	91.99%	8.01%
MDEM1	Peak Design Day	73.30%	22.65%	4.05%	100.00%	0.00%
MDEM3	50 / 50 Peak Design Day, Annual Firm Sales	64.62%	28.34%	7.04%	100.00%	0.00%
MDEM4	50 / 50 Peak Design Day, Annual Sales	52.00%	20.66%	4.78%	77.43%	22.57%
MDTHR	Annual Sales	30.69%	18.67%	5.50%	54.87%	45.13%
MENE2	Over/Under Collection - Cost of Gas	579.58%	-445.16%	-34.42%	100.00%	0.00%
METHR	Cost of Gas - Direct Assignment	35.20%	23.24%	1.67%	60.11%	39.89%
METHRF	Residential and SGS Cost of Gas	60.23%	39.77%	0.00%	100.00%	0.00%
MFFEE	Franchise Fees	52.96%	32.59%	1.41%	86.96%	13.04%
MRSL	Sales Revenues	39.01%	24.30%	1.69%	65.00%	35.00%
MTRSL	Transportation Revenue	0.00%	0.00%	88.20%	88.20%	11.80%
MWRSL	Sales Revenue net of Unbilled and Over/Under	61.61%	38.39%	0.00%	100.00%	0.00%
RB_A_OTH_PP	Prepayments	9.70%	53.70%	-4.45%	58.95%	41.05%
RB_A_PLT	Net Plant	71.82%	23.16%	3.68%	98.66%	1.34%
RB_A_PLT_??_O	Gross Plant	71.62%	23.31%	3.72%	98.65%	1.35%
RB_A_PLT_DI_O	Gross Distribution Plant	70.88%	23.84%	3.85%	98.57%	1.43%
RB_A_PLT_DI_O__378	Plant Accounts 378, 385	35.82%	15.22%	8.27%	59.30%	40.70%
RB_A_PLT_DI_O__ALOC	Plant Accounts 376, 380	73.86%	21.92%	4.15%	99.94%	0.06%
RB_A_PLT_DI_R	Distribution Plant Reserves	70.88%	23.84%	3.85%	98.57%	1.43%
RB_A_PLT_IN_R	Intangible Plant Reserves	90.83%	9.00%	0.05%	99.88%	0.12%
RB_A_PLT_PR_O	Gross Production Plant	73.30%	22.65%	4.05%	100.00%	0.00%
RB_A_PLT_PR_R	Production Plant Reserves	73.30%	22.65%	4.05%	100.00%	0.00%
REV_A_	Total Revenue	38.81%	24.11%	2.37%	65.30%	34.70%
WORK155	Plant Accounts 376, 380, 385	71.93%	24.10%	3.72%	99.74%	0.26%
WORKBATA	Rate Base less Average Tax Accrual	72.08%	22.86%	3.76%	98.71%	1.29%
WORKPD	Gross Production, Distribution Plant	70.93%	23.82%	3.85%	98.60%	1.40%
WORKPDR	Production, Distribution Reserves	70.96%	23.81%	3.85%	98.61%	1.39%